COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Massachusetts Electric Company }   D.P.U. Docket No. 96-25
}

ENVIRONMENTAL AND RENEWABLE PROVISIONS OF NEES SETTLEMENT AGREEMENTC
HIGHER COST FOR NO MEASURABLE BENEFIT

TESTIMONY OF THOMAS A HEWSON JR

Question: *What is your name and educational background?*

My Name is Thomas A Hewson Jr. I graduated in 1976 with a BSE degree in Civil Engineering from Princeton University.

Question: *What is your current Position ?*

Since December 1981, I have been a principal at Energy Ventures Analysis Inc, an energy and environmental consulting firm located in Arlington, Virginia.

Question: *Briefly describe your relevant qualifications to this proceeding.*

As part of our consulting practice, I have conducted numerous assessments and presented several papers on the effects of environmental regulation on the electric power industry. I have directed several research projects for the Electric Power Research Institute on the effects of the 1990 Clean Air Act and utility deregulation on utility fuel markets, transportation carriers and technology markets. My EPRI work also includes evaluating the competitiveness and marketability of future emerging and advanced generation options. For private clients, my projects have ranged from consulting with industry and Congressional staff during the development of the 1990 Clean Air Act to the development of individual utility emission allowance trading programs. I currently prepare quarterly emission allowance forecasts on the value of sulfur dioxide. I am also actively involved in several assessment on the cost and price impacts of regional NOx reduction policies being considered as part of an coordinated ozone attainment strategy. As part of this work, I evaluated the potential value of NOx emission credits. My resume is attached.

Question: Have you reviewed the environmental sections of the Settlement Agreement ?

Yes I have.

Question: Please state your conclusions briefly.

Attachment 10 of the Settlement Agreement would set emission reduction requirements beyond current Federal and State environmental requirements. To meet these stricter requirements, the station owners will incur incrementally higher compliance costs that will increase their production costs. These higher production costs will diminish the sales market value of the generating stations, thereby increasing NEES=s stranded costs. These higher production costs will also be passed through to the consumer as higher energy costs. While increasing costs, these more stringent emission reduction requirements are unlikely to yield any measurable environmental benefit. In some cases, local ozone levels may increase.

Question: Does the proposed Settlement Agreement include a provision to reduce air emissions at New England Power=s two steam-electric generating stations located in Massachusetts - Salem Harbor and Brayton PointCwhich go beyond current Federal and State environmental law ?

Yes, the Settlement Agreement establishes more stringent emission limitations for both sulfur dioxide (SO2) and nitrogen dioxide (NOx) than required by current Federal and State law for these two Massachusetts stations.

Question: How much more stringent are the proposed limitations than current State and Federal requirements ?

I estimate that the Settlement Agreement, when the requirements are fully phased in 2010, will reduce allowable NOx emissions by roughly 12,000 tons per year and allowable SO2 emissions by 60,000 tons per year beyond current Federal/State requirements. My estimates closely match the estimates provided on the charts contained in Attachment 10 of the Settlement Agreement.

For NOx, the Settlement Agreement establishes a <u>year</u> <u>round</u> <u>emissions</u> <u>cap</u> for NOx emissions of approximately 10,000 tons per year that will be phased in as units reach 40 years of service but no later than 2010. This NOx cap limit is calculated assuming a 0.15 lb. NOx/MMBtu emission rate, a 10,000 Btu/kWh heatrate and 8 year average unit generation. This tonnage cap limit is much stricter than either the current or proposed NOx limitations applicable to the stations.

Applicable year round NOx emission rate limitations are contained in the Massachusetts State Implementation Plan (SIP) and 1990 Clean Air Act Title IV requirements. For example, the existing applicable emission rate limits are 0.45 lb. NOx/MMBtu for Salem Harbor units #1-3 and 0.38 lb. NOx/MMBtu for Brayton Pt units #1-2.

The Commonwealth as part of its Title I ozone attainment strategy is considering establishing a more stringent NOx emissions cap applicable only during the Aozone season@ (May 1-September 30)[1]. The Massachusetts strategy would be part of a broader regional compliance strategy developed by the Ozone Transport Commission which is comprised of the 12 Northeastern states. Under a September 24, 1994 Memorandum of Understanding, Massachusetts would require its major stationary sources during the Aozone season@ to achieve either a 65% reduction in NOx emissions from 1990 base levels or 0.20 lb. NOx/MMBtu by May 1, 1999. This seasonal requirement may then be increased to a 75% reduction level from 1990 base levels or 0.15 lb. NOx/MMBtu by May 1, 2003. However, the year 2003 limitation is conditional and could be revised depending upon further air quality modeling results or other events influencing allowable air emissions.

If the strict emission tonnage limitations contained in the September 24, 1994 Ozone Transport Commission Memorandum of Understanding are adopted for the ozone season (May 1-September 30) and units meet the SIP emission rate limits during the other months (October 1-April 30), the two powerplants would have allowable emissions of approximately 22,000 tons per year of NOx after 2003. If the conditional 2003 limitation is not adopted, the allowable emissions would be higher, nearly 24,000 tons per year. By contrast, the Settlement Agreement would limit NOx emissions to about 10,000 tons per year.

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Rain SO2 tonnage emission allocation[2] (approximately 80,000 tons per year).

Question: How may the additional emission reductions prescribed in the Settlement Agreement be achieved ?

The station owners are allowed to meet these emission reductions through a combination of retrofitted post combustion controls (e.g. Flue Gas Desulfurization scrubbers for SO2 and Selective Catalytic Reduction for NOx), fuel switching, emission allowance trades, consumption of Abanked@ credits, reduced unit utilization or retirement.

Since NEES has evidentially not studied how it would meet these stricter limits, one must project a compliance strategy based upon our current knowledge of pollution control technology cost, performance and station layout. The two stations do have severe site constraints which would make retrofitting FGD and SCR equipment more expensive. I would anticipate the station owners would comply with the stricter sulfur dioxide limits at the coal and residual oil units (Salem Harbor #1-4, Brayton Pt#1-3) through (i) the accelerated consumption of Abanked@ SO2 credits[3] and (ii) purchase of additional emission credits. Brayton Point #4 would likely comply with the stricter limits through (i) reducing its residual oil consumption by burning more natural gas and (ii) use of banked/purchased credits.

For NOx compliance, the stations would likely (i) operate throughout the year (not just ozone season) the retrofitted NOx controls required to meet the Memorandum of Understanding requirements for 2003 (likely selective catalytic reduction equipment at Brayton Pt #1-3 and continued operation of SNCR at Salem Harbor #1-3), (ii) purchase additional NOx credits and (iii) reduce unit utilization of residual oil. If the conditional 2003 limit is not adopted, the Settlement Agreement may trigger the need to invest in SCR controls at Brayton Point.

Question: Will these more stringent emission reductions increase the station compliance

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[2] Under the 1990 Clean Air Act, EPA was authorized to distribute sulfur dioxide emission allowances to electric utility generating stations which totaled the prescribed emission tonnage targets. The amount of emissions allocated to each unit was based upon a formula contained in the legislation. Both Brayton Point and Salem Harbor qualified for emission allocations effective January 1, 2000. By being designated a compensating unit for Ohio Edison, NEES qualified earlier for emission allocations beginning in 1995.

[3] EPA reported NEES having created 12,069 in surplus emission credits from Brayton Point #1-4 and Salem Harbor #1-3 being designated as compensating units for Ohio Edison in 1995. These emission credits were Abanked@ for future consumption. I would anticipate that NEES would continue creating and banking additional surplus credits during the period 1996-1999.

costs ?

Yes, there are no Afree@ emission reductions.

Beginning in 2000, Salem Harbor will need to reduce its SO2 emissions by roughly 20,000 tons per year below its Phase II allocation and reduce its NOx by roughly 2,000-3,000 tons per year. These additional reduction requirements would cost approximately $4-6 million (in 1996$) [$5-7 million in current $] in the first year and escalate to $30-35 million (1996$)/year [$45-50 million/year in current $] by 2010 as the emission reduction requirement increases and the market value of emission credits rises.

For SO2, Salem Harbor may initially consume NEES=s Abanked@ emission allowances at an accelerated rate. We project these Abanked@ credits would have a market value in 2000 of between $100-120/ton (1996$). For NOx, the station would need to operate its SNCR equipment year round (incurring higher operating and maintenance costs), purchase NOx credits (if available), and reduce its residual oil burn. For Salem Harbor, we estimate the incremental reductions from SNCR operation would be between $1,200-1,400/ton (1996$) of NOx removed. The value of purchased NOx credits is much less certain since (i) no national NOx trading program exists and (ii) the OTC seasonal NOx trading program is still in its infancy and will likely be limited to trades for Aseasonal@ ozone credits. Under most likely outcomes, the cost for NOx credits could range from $1,500-3,000/ton ($1996$) to be sufficient to pay the source=s incremental removal costs and a profit. Displacing oil generation with purchased power is estimated at roughly $ 3,500-5,000/ton (1996) of NOx.

Between 2004-2010, additional emission reduction requirements would be phased in under the Settlement Agreement for the Brayton Point units. Eventually, the two stations would face an additional reduction requirement of 60,000 tons per year of SO2 and 12,000-14,000 tons per year of NOx beyond current federal/state requirements. Not only do the emission reduction requirements increase but also the market values of SO2 and NOx credits also increase as power suppliers consume their banked allowances and are forced to implement higher marginal cost compliance options. These higher incremental compliance costs are passed through to the emission allowance purchasers as higher market prices. By 2010, we project that credit values will reach $210/ton (1996$) for SO2 and $2,000/ton (1996$) for NOx. The combination of rising credit values and more stringent limitations resulting from the Settlement Agreement will cause incremental compliance costs to rise to $30-35 million

(1996$) per year by 2010 [$45-50 million/year in current $].

Overall, the environmental compliance actions triggered by the Settlement Agreement would increase the six coal-fired units= production cost by $ 3.20/MWh (1996$) (9-12 percent above their 1995 level). If these compliance passed onto without a mark-up to the residential consumer in Massachusetts,[4] the average additional cost would be $ 21 (1996$) or $32 (current $) per year per residential user.

Question: Will the incremental emission reduction requirement in the proposed Settlement Agreement result in ratepayers bearing the compliance cost as part of their stranded cost recovery ?

The additional emission reduction requirements proposed by the Settlement Agreement will diminish the market value of both the Salem Harbor and Brayton Point stations. As discussed earlier, the additional emission reduction requirements will increase generating production costs by $4-6 million/year (1996$) [$5-7 million/year in current $] and escalate to $ 30-35 million/year (1996$) [$45-50 million/year in current $]. If the Settlement Agreement is enacted, the purchaser would, at the minimum, drop the bid price by the net present value of these increased expenditures plus a risk premium. The net result is a lower sales price than would have otherwise been received had the environmental reduction requirement not been adopted. A lower asset sale price will result in a higher contract termination charge under the terms of the Settlement Agreement.

The fact that the proposed emission reductions would increase contract termination charges by ratepayers means that the proposal runs directly contrary to the Board=s May 1, 1996 policy statement with respect to the environmental consequences of restructuring. On page 38 of the policy statement, the Board emphasized that >(i)n the interest of establishing a level playing field in generation, the Department has previously determined that electric companies will not be allowed to collect going forward costs for environmental compliance in their stranded cost recovery mechanism.@ But as seen, the Settlement Agreement would effectively increase stranded cost payments by ratepayers as a result of complying with more stringent emission reductions required by the Settlement. Thus, the ratepayers are ultimately responsible for paying the going forward costs of environmental compliance in contravention

[4] Based upon the average Massachusetts residential power customer consumption of 6,700 kWh/year as reported in US Energy Information Agency=s report *Electric Sales and Revenue 1994* (Nov 1995.

of the policy statement and previous Department policy determinations.

Question: Will the incremental emission reduction requirement in the Settlement Agreement affect the power prices in Massachusetts ?

Yes. Higher contract termination charges from the greater emission reduction requirement will result in higher power rates. In addition, the increased production costs at both stations due to the more stringent environmental limitations will be passed through to power customers, many of whom will likely be Massachusetts customers. When these units set the sales price, the power sales price will be set at a higher rate with the Settlement=s environmental requirements than without them.

Question: Will these incremental emission reductions create any additional significant or measurable environmental benefits in Massachusetts ?

These reductions are not likely to create any significant or measurable environmental benefits in Massachusetts. As I testified earlier, a portion of the increased emission reduction requirement will probably be met through purchased SO2 and NOx credits. These credits would be likely be created from out-of state sources. Any environmental benefits from these purchased emission credits therefore would likely be recognized in areas outside Massachusetts and have no measurable benefit to the Commonwealth.

I would not anticipate any measurable benefit from incremental emission reductions even if made within the Commonwealth. The Commonwealth is already in compliance with primary ambient air quality standards for both sulfur dioxide and nitrogen dioxide. These ambient air quality standards have been set by EPA at a level necessary to protect the public health and welfare without regard to cost and must include an adequate margin of safety. Therefore, *there can be no further measurable environmental or public health benefits at ambient air quality levels below the existing primary and secondary ambient air quality standards*. These ambient air quality standards are periodically reviewed by an independent scientific review panel to assure that they reflect the most current scientific and medical data. The independent review of the sulfur dioxide and nitrogen dioxide air quality standards were completed this year. The scientific review committee found no basis to change the existing standards or establish a new secondary standards.

One possible benefit for reducing NOx emissions is to lower ozone levels since NOx is a component of the complex photochemical process creating ground level ozone (commonly known as Asmog@). Any method which would reduce ozone in Massachusetts would create an environmental benefit since the state is designated as a severe ozone non-attainment area. However, ozone is a product of a complex photochemical reaction, making its control difficult and specific to the local air chemistry and weather. In some cases, reducing stationary source NOx emissions accelerates the photochemical reaction and increases local ozone levels. According to the National Research Council=s 1991 report entitled ARethinking the Ozone Problem in Urban and Regional Air Pollution,@ NOx controls *can be counterproductive* for controlling local ozone levels at VOC/NOx ratios of 10 or less. In other cases, decreasing NOx emissions may reduce ozone levels downwind. The 1991 NRC report suggests that regional NOx reduction strategies would be most effective at VOC/NOx ratios of greater than 20.

NEES has evidentially not performed any study demonstrating the effect on local air quality from reducing NOx emissions at Brayton Point and Salem Harbor. Available data that I have seen suggest that most major metropolitan cities in the Northeast have VOC/NOx ratios of less than 10. If this trend was true for most areas in Massachusetts*, NOx reductions at Salem Harbor and Brayton Point stations during the critical summer season may be counterproductive and contribute to local ozone level increases*.

Unlike the seasonal NOx control approaches being pursued for ozone attainment by OTAG and several states, the Settlement Agreement would require year round reductions. The NOx reductions during the cooler non-ozone season would also have no measurable environmental benefit. During these periods, Massachusetts is already in compliance with the ozone standard.

Question: Would the incremental emission reduction requirements in the Settlement Agreement create a Alevel playing field@ for electric generators ?

No. The proposed reduction requirements would be applicable to Brayton Point and Salem Harbor independent of whether similar emission reduction requirements are adopted for other units in Massachusetts or for other units located within the region. Neither Massachusetts, NEES or any Settlement Agreement signatory has the authority to require similar emission reductions from competing out of state utilities. Nor has a similar emission reduction approach been adopted for the other in-state electric generating units.

This Ago it alone@ approach can result in economic harm to Massachusetts. Increasing the production costs only at the Salem Harbor and Brayton Point stations as a result of stricter emission limits while other units are not subject to these controls undermines the competitiveness of these stations. Even if the reduction requirements are extended to the other Massachusetts powerplants, Massachusetts would be placed at a competitive disadvantage to other units[5].

As I testified earlier, the proposed reduction requirements, if implemented, are likely to provide no measurable environmental benefit. As a result, this environmental provision of the Settlement Agreement creates an economic harm without producing an environmental good.

Question: Have you reviewed the conservation and renewable sections of the Settlement Agreement ?

Yes, I have. In my testimony, I would like to focus on the Aclean@ renewable sections of the proposal which is one element of this section.

Question: Please briefly state your conclusions.

Renewable technologies are often promoted as being more environmentally friendly than conventional fossil fuel alternatives. However, for many renewable projects, these claims may be more a myth than fact. Renewable technologies often have higher emissions and/or pose significant environmental issues. These environmental problems have led to opposition of Aclean@ renewable projects by several environmental groups and governmental agencies.

Supporters also contend that these technologies require temporary subsidies to promote their commercial development, leading to further technological improvements that will make them more competitive in the future. Unfortunately, even with technological improvements, they will remain higher cost than conventional alternatives. Significant subsidies in the form of tax credits are already in place for these technologies and yet most projects remain non-

[5] This conclusion is consistent with the Board=s May 1, 1996 policy statement which indicated that emission limitations need to be applied on an interstate and regional basis both from the standpoint of achieving environmental benefits and from the standpoint of creating an economic level playing field for electric generators. However, as we testified, this appears not to be accomplished by this settlement agreement.

competitive.

The Settlement Agreement would continue to add to these existing subsidies and set a high goal for purchases of Aclean@ renewable generation. The Settlement Agreement includes funds as part of the contract termination charges to cover costs from Aabove market@ renewable power contracts. Another charge is also apparently assessed (under section III C of Restructuring Agreement) to support commercialization and development of Aclean@ renewable technologies. However, these charges will likely be insufficient to achieve the renewable sales goal without additional subsidies.

Question: Does Aclean@ renewable generation have negative environmental impacts?

Yes, most definitely. Just because they are Arenewable@ technologies does not mean they do not create environmental impacts.

Municipal solid waste (MSW) projects generally have higher air emissions than conventional fossil fuel generation alternatives. Below is a comparison between NEES coal-fired units and a >typical@ MSW plant:

	MSW	Salem Harbor/Brayton Pt Coal
NOx (#/MWh)	5.0	2.9-3.1
CO2 (#/MWh)	10,400	1,900-2,200
Heatrate Efficiency (%)	20-21%	30-37%

This Arenewable@ MSW alternative has higher NOx and CO2 emissions than NEES coal-fired units targeted for additional emission reductions. Although MSW fuel is essentially free, high capital investment cost (approx. $7,000/kW) make MSW a less competitive power producer. These MSW facilities were built to solve a growing solid waste problem and reduce volumes going into landfillsCnot to provide a low cost energy source. As a result, one should question the need for ratepayers to subsidize these projects since their decision to proceed is not based upon power prices but solving local landfill constraints.

Biomass projects can also have higher air emissions than conventional generation alternatives. For example, one can compare 1995 air emissions at the affected NEES coal fired units and the McNeil station, a large wood burning plant in Burlington, Vermont:

	McNeil	Salem Harbor/Brayton Pt Coal
NOx (#/MWh)	2.5	2.9-3.1
CO2 (#/MWh)	3,500	1,900-2,200
Heatrate Efficiency (%)	23%	30-37%

The coal-fired Salem Harbor/Brayton Pt. units have a NOx emission rate approximately the same per MWh output than a biomass plant. However, if we compare biomass emissions to the newer fossil fuel units, the new fossil fuel units can have much lower rates that can reach as low as 1.0 lb. NOx/MWh for a pulverized coal-fired unit and 0.4 lb. NOx/MWh for a gas-fired combined cycle plant or coal-fired integrated gasification combined cycle plant. Hydroelectric generation, which is not considered a renewable technology under the Settlement Agreement, would have the lowest air emissions.

The NEES coal-fired units have a much lower carbon dioxide emission rate than biomass plants. One reason for biomass technologies having potentially higher emissions is poorer energy efficiencies caused by biomass having a lower heat content (from high moisture content in case of wood fuels).

Wind power also creates environmental impacts which have led to opposition to wind farm projects by governmental agencies and environmental groups. Environmental issues include bird life losses, increased noise and high land use requirements. The US Fish and Wildlife Service has challenged two Washington wind farm projects because they were in the migratory path of Aprotected species.@ Their concerns have been raised by documented experiences at existing wind farms. Noise is also a frequent complaint of windmill neighbors. Finally, the smaller capacity sizes of windmills cause wind farm projects to need more windmills and occupy land areas that often far exceed conventional generation alternatives.

Finally, smaller renewable projects may not be subject to as strict environmental requirements as larger, more efficient, conventional fossil fuel-fired plants. Their smaller size may allow them to avoid the strict controls and monitoring/reporting requirements applicable to major stationary sources. As a result, aggregated power industry emissions could be higher.

Question: What is the stated renewable goal in the Settlement Agreement ?

The Settlement Agreement establishes a Aclean@ renewable goal of 4 percent of Massachusetts power sales by 2007. This goal is non-enforceable and may be revised based upon market barriers and experience. Four percent of 1994 Massachusetts power sales were 1,844 GWh. Under this settlement, this goal would increase with load growth and could reach 2,400 GWh by 2007 (@2%/yr growth) or higher. Since hydroelectric power is not defined as a renewable technology, this goal will involve expanding existing renewable capacity.

Question: How much would it cost to achieve this renewable sales goal ?

Unfortunately, renewable technologies do not have low production costs as evidenced by current experience in New England. Under the Settlement Agreement, Massachusetts ratepayers will already pay NEES for its existing Aabove market@ renewable power contract obligations as part of its contract termination charges. These charges would just be an initial down payment if Massachusetts fulfills its stated renewable sales goal.

Several NUG biomass powerplants were built in the Northeast, mostly burning wood and wood wastes as fuel. These plants have been unable to compete effectively in the high priced New England market because of their poor energy efficiency (<24%) and high delivered local wood prices (>$2.00/MMBtu). Having high production costs, several NUG biomass powerplant contracts in Maine were bought out in the past 2 years and were switched to dispatchable contracts. With dispatchable contracts, these units had capacity factors of less than 5%, were eventually closed and offered for sale by their owners.

Wind power has also been largely uneconomic because of the high capital costs, poor availability and small size. Being unpredictable, wind power is unable to guarantee capacity availability for high cost peak periods so it must compete on an energy basis alone, which is the power=s lowest value market[6] (also the night breezes occur during off-peak times when energy prices are the lowest). Being unable to offer competitive power options without significant subsidies, Kenetech, the leading wind mill vendor, was forced to file for Chapter 11 protection.

Based upon current knowledge of present and future renewable technologies, projected renewable generating costs will likely range from 7-15 cents per kWh (1996$). These production costs will remain far above the current generating costs of 2-3 cent/kWh for

[6] Massachusetts has no Class 4, 5 or 6 areas making it a less attractive site (less power output, less poorer availability) than some Northwestern and upper New England sites.

existing baseload fossil fuel units or the 3-5 cents/kWh for new fossil fuel fired power generation alternatives. Therefore, the consumer must be willing to pay much higher power prices for renewable power. Assuming Aclean@ renewable production costs remain approximately $0.075/kwh more expensive than conventional generation, a subsidy of $150-180 million/year (1996$) would be required to achieve the renewable goal set forth in the Settlement. If this subsidy is captured only from Massachusetts Electric customers[7], a charge of $ 8-10/MWh (1996$) would be required to meet the 2007 target. At average residential consumption rates, these charges would add $50-70 (1996$) per year to residential customer bills. A lower charge could be assessed if the charges were spread across all customers in Massachusetts.

Question: Are the current subsidies contained in the Settlement Agreement sufficient to meet the 4 percent goal ?

No, the power subsidies set forth in the section III B of the Restructuring Agreement would be insufficient to achieve the 4 percent target at projected renewable generation costs. The charges would have to be increased and extended to expand beyond research and development expenditures and subsidize the difference between the market clearing price and the higher price of renewable generation in order to meet the policy goal. Given the projected costs for future renewable fuel generation, insufficient funds would be raised to achieve the stated 4 percent goal. Unless the charges are increased, the 4 percent goal would have to be lowered to meet funding targets. In either case, Massachusetts customers will pay more for power when any high cost generation option is subsidized.

Question: Are renewable subsidies consistent with a deregulated power market ?

No. The purpose of deregulation is to allow the market to choose winners and losers among electric suppliers. The free market is undermined when the government steps in and decides that a certain type of product should be preferred over another type.

I am aware that the Department believes that there are certain barriers to market penetration by renewable resources that justify renewable subsidies. While I do not agree with this belief as I outlined in my testimony, I would suggest that the existence of these barriers does not

[7] According to Schedule 1 contained in Book 2 pg. 62, the estimated 2007 Massachusetts Electric Power sales in 2007 will be 18,845 GWh.

justify that renewables be subsidized, in effect, forever. In a deregulated market, renewable power providers will be free to market their product directly to customers who are willing to pay a premium for what they perceive to be a Agreen@ product. Several current examples exist of customers in an open power market paying a premium for perceived Agreen@ power. There is no reason why a similar renewable power market could not be created in Massachusetts without subsidies.

To the extent that the Department believes that renewables continue to need subsidies, I would recommend that they be limited to four years in order to give renewable providers a period to Atransform the market@ and create a market, despite their higher cost. The California legislature has adopted a similar approach which, in effect, has limited renewable subsidies to a four year period. The legislature=s view was that the free market should prevail, but that California=s past support for renewables should not be terminated without a transition period. Perhaps, Massachusetts could adopt the same approach.

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Since NEES has evidentially not studied how it would meet these stricter limits, one must project a compliance strategy based upon our current knowledge of pollution control technology cost, performance and station layout. The two stations do have severe site constraints which would make retrofitting FGD and SCR equipment more expensive. I would anticipate the station owners would comply with the stricter sulfur dioxide limits at the coal and residual oil units (Salem Harbor #1-4, Brayton Pt#1-3) through (i) the accelerated consumption of "banked" SO2 credits[10] and (ii) purchase of additional emission credits. Brayton Point #4 would likely comply with the stricter limits through (i) reducing its residual oil consumption by burning more natural gas and (ii) use of banked/purchased credits.

For NOx compliance, the stations would likely (i) operate throughout the year (not just ozone season) the retrofitted NOx controls required to meet the Memorandum of Understanding requirements for 2003 (likely selective catalytic reduction equipment at Brayton Pt #1-3 and continued operation of SNCR at Salem Harbor #1-3), (ii) purchase additional NOx credits and (iii) reduce unit utilization of residual oil. If the conditional 2003 limit is not adopted, the Settlement Agreement may trigger the need to invest in SCR controls at Brayton Point.

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[9] Under the 1990 Clean Air Act, EPA was authorized to distribute sulfur dioxide emission allowances to electric utility generating stations which totaled the prescribed emission tonnage targets. The amount of emissions allocated to each unit was based upon a formula contained in the legislation. Both Brayton Point and Salem Harbor qualified for emission allocations effective January 1, 2000. By being designated a compensating unit for Ohio Edison, NEES qualified earlier for emission allocations beginning in 1995.

[10] EPA reported NEES having created 12,069 in surplus emission credits from Brayton Point #1-4 and Salem Harbor #1-3 being designated as compensating units for Ohio Edison in 1995. These emission credits were "banked" for future consumption. I would anticipate that NEES would continue creating and banking additional surplus credits during the period 1996-1999.

Question: Will these more stringent emission reductions increase the station compliance costs ?

Yes, there are no “free” emission reductions.

Beginning in 2000, Salem Harbor will need to reduce its SO2 emissions by roughly 20,000 tons per year below its Phase II allocation and reduce its NOx by roughly 2,000-3,000 tons per year. These additional reduction requirements would cost approximately $4-6 million (in 1996$) [$5-7 million in current $] in the first year and escalate to $30-35 million (1996$)/year [$45-50 million/year in current $] by 2010 as the emission reduction requirement increases and the market value of emission credits rises.

For SO2, Salem Harbor may initially consume NEES’s “banked” emission allowances at an accelerated rate. We project these “banked” credits would have a market value in 2000 of between $100-120/ton (1996$). For NOx, the station would need to operate its SNCR equipment year round (incurring higher operating and maintenance costs), purchase NOx credits (if available), and reduce its residual oil burn. For Salem Harbor, we estimate the incremental reductions from SNCR operation would be between $1,200-1,400/ton (1996$) of NOx removed. The value of purchased NOx credits is much less certain since (i) no national NOx trading program exists and (ii) the OTC seasonal NOx trading program is still in its infancy and will likely be limited to trades for “seasonal” ozone credits. Under most likely outcomes, the cost for NOx credits could range from $1,500-3,000/ton ($1996$) to be sufficient to pay the source’s incremental removal costs and a profit. Displacing oil generation with purchased power is estimated at roughly $ 3,500-5,000/ton (1996) of NOx.

Between 2004-2010, additional emission reduction requirements would be phased in under the Settlement Agreement for the Brayton Point units. Eventually, the two stations would face an additional reduction requirement of 60,000 tons per year of SO2 and 12,000-14,000 tons per year of NOx beyond current federal/state requirements. Not only do the emission reduction requirements increase but also the market values of SO2 and NOx credits also increase as power suppliers consume their banked allowances and are forced to implement higher marginal cost compliance options. These higher incremental compliance costs are passed through to the emission allowance purchasers as higher market prices. By 2010, we project that credit values will reach $210/ton (1996$) for SO2 and $2,000/ton (1996$) for NOx. The combination of rising credit values and more stringent limitations resulting from the Settlement Agreement will cause incremental compliance costs to rise to $30-35 million

(1996$) per year by 2010 [$45-50 million/year in current $].

Overall, the environmental compliance actions triggered by the Settlement Agreement would increase the six coal-fired units' production cost by $ 3.20/MWh (1996$) (9-12 percent above their 1995 level). If these compliance passed onto without a mark-up to the residential consumer in Massachusetts,[11] the average additional cost would be $ 21 (1996$) or $32 (current $) per year per residential user.

Question: Will the incremental emission reduction requirement in the proposed Settlement Agreement result in ratepayers bearing the compliance cost as part of their stranded cost recovery ?

The additional emission reduction requirements proposed by the Settlement Agreement will diminish the market value of both the Salem Harbor and Brayton Point stations. As discussed earlier, the additional emission reduction requirements will increase generating production costs by $4-6 million/year (1996$) [$5-7 million/year in current $] and escalate to $ 30-35 million/year (1996$) [$45-50 million/year in current $]. If the Settlement Agreement is enacted, the purchaser would, at the minimum, drop the bid price by the net present value of these increased expenditures plus a risk premium. The net result is a lower sales price than would have otherwise been received had the environmental reduction requirement not been adopted. A lower asset sale price will result in a higher contract termination charge under the terms of the Settlement Agreement.

The fact that the proposed emission reductions would increase contract termination charges by ratepayers means that the proposal runs directly contrary to the Board's May 1, 1996 policy statement with respect to the environmental consequences of restructuring. On page 38 of the policy statement, the Board emphasized that '(i)n the interest of establishing a level playing field in generation, the Department has previously determined that electric companies will not be allowed to collect going forward costs for environmental compliance in their stranded cost recovery mechanism." But as seen, the Settlement Agreement would effectively increase stranded cost payments by ratepayers as a result of complying with more stringent emission reductions required by the Settlement. Thus, the ratepayers are ultimately

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[11] Based upon the average Massachusetts residential power customer consumption of 6,700 kWh/year as reported in US Energy Information Agency's report <u>*Electric Sales and Revenue 1994*</u> (Nov 1995.

responsible for paying the going forward costs of environmental compliance in contravention of the policy statement and previous Department policy determinations.

Question: Will the incremental emission reduction requirement in the Settlement Agreement affect the power prices in Massachusetts ?

Yes. Higher contract termination charges from the greater emission reduction requirement will result in higher power rates. In addition, the increased production costs at both stations due to the more stringent environmental limitations will be passed through to power customers, many of whom will likely be Massachusetts customers. When these units set the sales price, the power sales price will be set at a higher rate with the Settlement's environmental requirements than without them.

Question: Will these incremental emission reductions create any additional significant or measurable environmental benefits in Massachusetts ?

These reductions are not likely to create any significant or measurable environmental benefits in Massachusetts. As I testified earlier, a portion of the increased emission reduction requirement will probably be met through purchased SO2 and NOx credits. These credits would be likely be created from out-of state sources. Any environmental benefits from these purchased emission credits therefore would likely be recognized in areas outside Massachusetts and have no measurable benefit to the Commonwealth.

I would not anticipate any measurable benefit from incremental emission reductions even if made within the Commonwealth. The Commonwealth is already in compliance with primary ambient air quality standards for both sulfur dioxide and nitrogen dioxide. These ambient air quality standards have been set by EPA at a level necessary to protect the public health and welfare without regard to cost and must include an adequate margin of safety. Therefore, *there can be no further measurable environmental or public health benefits at ambient air quality levels below the existing primary and secondary ambient air quality standards*. These ambient air quality standards are periodically reviewed by an independent scientific review panel to assure that they reflect the most current scientific and medical data. The independent review of the sulfur dioxide and nitrogen dioxide air quality standards were completed this year. The scientific review committee found no basis to change the existing standards or establish a new secondary standards.

One possible benefit for reducing NOx emissions is to lower ozone levels since NOx is a component of the complex photochemical process creating ground level ozone (commonly known as "smog"). Any method which would reduce ozone in Massachusetts would create an environmental benefit since the state is designated as a severe ozone non-attainment area. However, ozone is a product of a complex photochemical reaction, making its control difficult and specific to the local air chemistry and weather. In some cases, reducing stationary source NOx emissions accelerates the photochemical reaction and increases local ozone levels. According to the National Research Council's 1991 report entitled "Rethinking the Ozone Problem in Urban and Regional Air Pollution," NOx controls *can be counterproductive* for controlling local ozone levels at VOC/NOx ratios of 10 or less. In other cases, decreasing NOx emissions may reduce ozone levels downwind. The 1991 NRC report suggests that regional NOx reduction strategies would be most effective at VOC/NOx ratios of greater than 20.

NEES has evidentially not performed any study demonstrating the effect on local air quality from reducing NOx emissions at Brayton Point and Salem Harbor. Available data that I have seen suggest that most major metropolitan cities in the Northeast have VOC/NOx ratios of less than 10. If this trend was true for most areas in Massachusetts*, NOx reductions at Salem Harbor and Brayton Point stations during the critical summer season may be counterproductive and contribute to local ozone level increases*.

Unlike the seasonal NOx control approaches being pursued for ozone attainment by OTAG and several states, the Settlement Agreement would require year round reductions. The NOx reductions during the cooler non-ozone season would also have no measurable environmental benefit. During these periods, Massachusetts is already in compliance with the ozone standard.

Question: Would the incremental emission reduction requirements in the Settlement Agreement create a "level playing field" for electric generators ?

No. The proposed reduction requirements would be applicable to Brayton Point and Salem Harbor independent of whether similar emission reduction requirements are adopted for other units in Massachusetts or for other units located within the region. Neither Massachusetts, NEES or any Settlement Agreement signatory has the authority to require similar emission reductions from competing out of state utilities. Nor has a similar emission reduction approach been adopted for the other in-state electric generating units.

This "go it alone" approach can result in economic harm to Massachusetts. Increasing the production costs only at the Salem Harbor and Brayton Point stations as a result of stricter emission limits while other units are not subject to these controls undermines the competitiveness of these stations. Even if the reduction requirements are extended to the other Massachusetts powerplants, Massachusetts would be placed at a competitive disadvantage to other units[12].

As I testified earlier, the proposed reduction requirements, if implemented, are likely to provide no measurable environmental benefit. As a result, this environmental provision of the Settlement Agreement creates an economic harm without producing an environmental good.

Question: Have you reviewed the conservation and renewable sections of the Settlement Agreement ?

Yes, I have. In my testimony, I would like to focus on the "clean" renewable sections of the proposal which is one element of this section.

Question: Please briefly state your conclusions.

Renewable technologies are often promoted as being more environmentally friendly than conventional fossil fuel alternatives. However, for many renewable projects, these claims may be more a myth than fact. Renewable technologies often have higher emissions and/or pose significant environmental issues. These environmental problems have led to opposition of "clean" renewable projects by several environmental groups and governmental agencies.

Supporters also contend that these technologies require temporary subsidies to promote their commercial development, leading to further technological improvements that will make them more competitive in the future. Unfortunately, even with technological improvements, they will remain higher cost than conventional alternatives. Significant subsidies in the form of

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[12] This conclusion is consistent with the Board's May 1, 1996 policy statement which indicated that emission limitations need to be applied on an interstate and regional basis both from the standpoint of achieving environmental benefits and from the standpoint of creating an economic level playing field for electric generators. However, as we testified, this appears not to be accomplished by this settlement agreement.

tax credits are already in place for these technologies and yet most projects remain non-competitive.

The Settlement Agreement would continue to add to these existing subsidies and set a high goal for purchases of "clean" renewable generation. The Settlement Agreement includes funds as part of the contract termination charges to cover costs from "above market" renewable power contracts. Another charge is also apparently assessed (under section III C of Restructuring Agreement) to support commercialization and development of "clean" renewable technologies. However, these charges will likely be insufficient to achieve the renewable sales goal without additional subsidies.

Question: Does "clean" renewable generation have negative environmental impacts?

Yes, most definitely. Just because they are "renewable" technologies does not mean they do not create environmental impacts.

Municipal solid waste (MSW) projects generally have higher air emissions than conventional fossil fuel generation alternatives. Below is a comparison between NEES coal-fired units and a 'typical" MSW plant:

	MSW	Salem Harbor/Brayton Pt Coal
NOx (#/MWh)	5.0	2.9-3.1
CO2 (#/MWh)	10,400	1,900-2,200
Heatrate Efficiency (%)	20-21%	30-37%

This "renewable" MSW alternative has higher NOx and CO2 emissions than NEES coal-fired units targeted for additional emission reductions. Although MSW fuel is essentially free, high capital investment cost (approx. $7,000/kW) make MSW a less competitive power producer. These MSW facilities were built to solve a growing solid waste problem and reduce volumes going into landfills—not to provide a low cost energy source. As a result, one should question the need for ratepayers to subsidize these projects since their decision to proceed is not based upon power prices but solving local landfill constraints.

Biomass projects can also have higher air emissions than conventional generation alternatives. For example, one can compare 1995 air emissions at the affected NEES coal fired units and the McNeil station, a large wood burning plant in Burlington, Vermont:

	McNeil	Salem Harbor/Brayton Pt Coal
NOx (#/MWh)	2.5	2.9-3.1
CO2 (#/MWh)	3,500	1,900-2,200
Heatrate Efficiency (%)	23%	30-37%

The coal-fired Salem Harbor/Brayton Pt. units have a NOx emission rate approximately the same per MWh output than a biomass plant. However, if we compare biomass emissions to the newer fossil fuel units, the new fossil fuel units can have much lower rates that can reach as low as 1.0 lb. NOx/MWh for a pulverized coal-fired unit and 0.4 lb. NOx/MWh for a gas-fired combined cycle plant or coal-fired integrated gasification combined cycle plant. Hydroelectric generation, which is not considered a renewable technology under the Settlement Agreement, would have the lowest air emissions.

The NEES coal-fired units have a much lower carbon dioxide emission rate than biomass plants. One reason for biomass technologies having potentially higher emissions is poorer energy efficiencies caused by biomass having a lower heat content (from high moisture content in case of wood fuels).

Wind power also creates environmental impacts which have led to opposition to wind farm projects by governmental agencies and environmental groups. Environmental issues include bird life losses, increased noise and high land use requirements. The US Fish and Wildlife Service has challenged two Washington wind farm projects because they were in the migratory path of "protected species." Their concerns have been raised by documented experiences at existing wind farms. Noise is also a frequent complaint of windmill neighbors. Finally, the smaller capacity sizes of windmills cause wind farm projects to need more windmills and occupy land areas that often far exceed conventional generation alternatives.

Finally, smaller renewable projects may not be subject to as strict environmental requirements as larger, more efficient, conventional fossil fuel-fired plants. Their smaller size may allow them to avoid the strict controls and monitoring/reporting requirements applicable to major stationary sources. As a result, aggregated power industry emissions could be higher.

Question: What is the stated renewable goal in the Settlement Agreement ?

The Settlement Agreement establishes a "clean" renewable goal of 4 percent of Massachusetts power sales by 2007. This goal is non-enforceable and may be revised based upon market barriers and experience. Four percent of 1994 Massachusetts power sales were 1,844 GWh. Under this settlement, this goal would increase with load growth and could reach 2,400 GWh by 2007 (@2%/yr growth) or higher. Since hydroelectric power is not defined as a renewable technology, this goal will involve expanding existing renewable capacity.

Question: *How much would it cost to achieve this renewable sales goal ?*

Unfortunately, renewable technologies do not have low production costs as evidenced by current experience in New England. Under the Settlement Agreement, Massachusetts ratepayers will already pay NEES for its existing "above market" renewable power contract obligations as part of its contract termination charges. These charges would just be an initial down payment if Massachusetts fulfills its stated renewable sales goal.

Several NUG biomass powerplants were built in the Northeast, mostly burning wood and wood wastes as fuel. These plants have been unable to compete effectively in the high priced New England market because of their poor energy efficiency (<24%) and high delivered local wood prices (>$2.00/MMBtu). Having high production costs, several NUG biomass powerplant contracts in Maine were bought out in the past 2 years and were switched to dispatchable contracts. With dispatchable contracts, these units had capacity factors of less than 5%, were eventually closed and offered for sale by their owners.

Wind power has also been largely uneconomic because of the high capital costs, poor availability and small size. Being unpredictable, wind power is unable to guarantee capacity availability for high cost peak periods so it must compete on an energy basis alone, which is the power's lowest value market[13] (also the night breezes occur during off-peak times when energy prices are the lowest). Being unable to offer competitive power options without significant subsidies, Kenetech, the leading wind mill vendor, was forced to file for Chapter 11 protection.

Based upon current knowledge of present and future renewable technologies, projected renewable generating costs will likely range from 7-15 cents per kWh (1996$). These production costs will remain far above the current generating costs of 2-3 cent/kWh for

[13] Massachusetts has no Class 4, 5 or 6 areas making it a less attractive site (less power output, less poorer availability) than some Northwestern and upper New England sites.

existing baseload fossil fuel units or the 3-5 cents/kWh for new fossil fuel fired power generation alternatives. Therefore, the consumer must be willing to pay much higher power prices for renewable power. Assuming "clean" renewable production costs remain approximately $0.075/kwh more expensive than conventional generation, a subsidy of $150-180 million/year (1996$) would be required to achieve the renewable goal set forth in the Settlement. If this subsidy is captured only from Massachusetts Electric customers[14], a charge of $ 8-10/MWh (1996$) would be required to meet the 2007 target. At average residential consumption rates, these charges would add $50-70 (1996$) per year to residential customer bills. A lower charge could be assessed if the charges were spread across all customers in Massachusetts.

Question: Are the current subsidies contained in the Settlement Agreement sufficient to meet the 4 percent goal ?

No, the power subsidies set forth in the section III B of the Restructuring Agreement would be insufficient to achieve the 4 percent target at projected renewable generation costs. The charges would have to be increased and extended to expand beyond research and development expenditures and subsidize the difference between the market clearing price and the higher price of renewable generation in order to meet the policy goal. Given the projected costs for future renewable fuel generation, insufficient funds would be raised to achieve the stated 4 percent goal. Unless the charges are increased, the 4 percent goal would have to be lowered to meet funding targets. In either case, Massachusetts customers will pay more for power when any high cost generation option is subsidized.

Question: Are renewable subsidies consistent with a deregulated power market ?

No. The purpose of deregulation is to allow the market to choose winners and losers among electric suppliers. The free market is undermined when the government steps in and decides that a certain type of product should be preferred over another type.

I am aware that the Department believes that there are certain barriers to market penetration by renewable resources that justify renewable subsidies. While I do not agree with this belief as I outlined in my testimony, I would suggest that the existence of these barriers does not

[14] According to Schedule 1 contained in Book 2 pg. 62, the estimated 2007 Massachusetts Electric Power sales in 2007 will be 18,845 GWh.

justify that renewables be subsidized, in effect, forever. In a deregulated market, renewable power providers will be free to market their product directly to customers who are willing to pay a premium for what they perceive to be a "green" product. Several current examples exist of customers in an open power market paying a premium for perceived "green" power. There is no reason why a similar renewable power market could not be created in Massachusetts without subsidies.

To the extent that the Department believes that renewables continue to need subsidies, I would recommend that they be limited to four years in order to give renewable providers a period to "transform the market" and create a market, despite their higher cost. The California legislature has adopted a similar approach which, in effect, has limited renewable subsidies to a four year period. The legislature's view was that the free market should prevail, but that California's past support for renewables should not be terminated without a transition period. Perhaps, Massachusetts could adopt the same approach.